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TO ALL WHOM IT MAY CONCERN:

Be it known that WE, JOHN D. WILKINSON and HANK M. HUDSON, both citizens of the United States, both residing in Midland, County of Midland, State of Texas, whose post office addresses are 2800 W. Dengar, Midland, Texas 79705 and 2508 W. Sinclair, Midland, Texas 79705, respectively, have invented an improvement in

LIQUEFIED NATURAL GAS PROCESSING

of which the following is a

SPECIFICATION

BACKGROUND OF THE INVENTION

[0001] This invention relates to a process for the separation of ethane and heavier hydrocarbons or propane and heavier hydrocarbons from liquefied natural gas, hereinafter referred to as LNG, to provide a volatile methane-rich residue gas stream and a less volatile natural gas liquids (NGL) or liquefied petroleum gas (LPG) stream.

[0002] As an alternative to transportation in pipelines, natural gas at remote locations is sometimes liquefied and transported in special LNG tankers to appropriate LNG receiving and storage terminals. The LNG can then be re-vaporized and used as a

gaseous fuel in the same fashion as natural gas. Although LNG usually has a major proportion of methane, i.e., methane comprises at least 50 mole percent of the LNG, it also contains relatively lesser amounts of heavier hydrocarbons such as ethane, propane, butanes, and the like, as well as nitrogen. It is often necessary to separate some or all of the heavier hydrocarbons from the methane in the LNG so that the gaseous fuel resulting from vaporizing the LNG conforms to pipeline specifications for heating value. In addition, it is often also desirable to separate the heavier hydrocarbons from the methane because these hydrocarbons have a higher value as liquid products (for use as petrochemical feedstocks, as an example) than their value as fuel.

[0003] Although there are many processes which may be used to separate ethane and heavier hydrocarbons from LNG, these processes often must compromise between high recovery, low utility costs, and process simplicity (and hence low capital investment). In U.S. Patent No. 2,952,984 Marshall describes an LNG process capable of very high ethane recovery via the use of a refluxed distillation column. Markbreiter describes in U.S. Patent No. 3,837,172 a simpler process using a non-refluxed fractionation column, limited to lower ethane or propane recoveries. Rambo et al describe in U.S. Patent No. 5,114,451 an LNG process capable of very high ethane or very high propane recovery using a compressor to provide reflux for the distillation column.

[0004] The present invention is generally concerned with the recovery of ethylene, ethane, propylene, propane, and heavier hydrocarbons from such LNG streams. It uses a novel process arrangement to allow high ethane or high propane recovery while

keeping the processing equipment simple and the capital investment low. Further, the present invention offers a reduction in the utilities (power and heat) required to process the LNG to give lower operating cost than the prior art processes. A typical analysis of an LNG stream to be processed in accordance with this invention would be, in approximate mole percent, 86.7% methane, 8.9% ethane and other C<sub>2</sub> components, 2.9% propane and other C<sub>3</sub> components, and 1.0% butanes plus, with the balance made up of nitrogen.

[0005] For a better understanding of the present invention, reference is made to the following examples and drawings. Referring to the drawings:

[0006] FIGS. 1, 2, and 3 are flow diagrams of prior art LNG processing plants in accordance with United States Patent No. 3,837,172;

[0007] FIGS. 4, 5, and 6 are flow diagrams of prior art LNG processing plants in accordance with United States Patent No. 2,952,984;

[0008] FIGS. 7, 8, and 9 are flow diagrams of prior art LNG processing plants in accordance with United States Patent No. 5,114,451;

[0009] FIG. 10 is a flow diagram of an LNG processing plant in accordance with the present invention;

[0010] FIGS. 11 through 18 are flow diagrams illustrating alternative means of application of the present invention to an LNG processing plant; and

[0011] FIGS. 19 and 20 are diagrams of alternative fractionation systems which may be employed in the process of the present invention.

[0012] In the following explanation of the above figures, tables are provided summarizing flow rates calculated for representative process conditions. In the tables appearing herein, the values for flow rates (in moles per hour) have been rounded to the nearest whole number for convenience. The total stream rates shown in the tables include all non-hydrocarbon components and hence are generally larger than the sum of the stream flow rates for the hydrocarbon components. Temperatures indicated are approximate values rounded to the nearest degree. It should also be noted that the process design calculations performed for the purpose of comparing the processes depicted in the figures are based on the assumption of no heat leak from (or to) the surroundings to (or from) the process. The quality of commercially available insulating materials makes this a very reasonable assumption and one that is typically made by those skilled in the art.

[0013] For convenience, process parameters are reported in both the traditional British units and in the units of the International System of Units (SI). The molar flow rates given in the tables may be interpreted as either pound moles per hour or kilogram moles per hour. The energy consumptions reported as horsepower (HP) and/or thousand British Thermal Units per hour (MBTU/Hr) correspond to the stated molar flow rates in pound moles per hour. The energy consumptions reported as kilowatts (kW) correspond to the stated molar flow rates in kilogram moles per hour.

DESCRIPTION OF THE PRIOR ART

[0014] Referring now to FIG. 1, for comparison purposes we begin with an example of an LNG processing plant in accordance with U.S. Pat. No. 3,837,172, adapted

to produce an NGL product containing the majority of the C<sub>2</sub> components and heavier hydrocarbon components present in the feed stream. The LNG to be processed (stream 41) from LNG tank 10 enters pump 11 at -255°F [-159°C]. Pump 11 elevates the pressure of the LNG sufficiently so that it can flow through heat exchangers and thence to fractionation tower 16. Stream 41a exiting the pump is split into two portions, streams 42 and 43. The first portion, stream 42, is expanded to the operating pressure (approximately 395 psia [2,723 kPa(a)]) of fractionation tower 16 by valve 12 and supplied to the tower as the top column feed.

[0015] The second portion, stream 43, is heated prior to entering fractionation tower 16 so that all or a portion of it is vaporized, reducing the amount of liquid flowing down fractionation tower 16 and allowing the use of a smaller diameter column. In the example shown in FIG. 1, stream 43 is first heated to -229°F [-145°C] in heat exchanger 13 by cooling the liquid product from the column (stream 47). The partially heated stream 43a is then further heated to 30°F [-1°C] (stream 43b) in heat exchanger 14 using a low level source of utility heat, such as the sea water used in this example. After expansion to the operating pressure of fractionation tower 16 by valve 15, the resulting stream 43c flows to a mid-column feed point at 27°F [-3°C].

[0016] Fractionation tower 16, commonly referred to as a demethanizer, is a conventional distillation column containing a plurality of vertically spaced trays, one or more packed beds, or some combination of trays and packing. The trays and/or packing provide the necessary contact between the liquids falling downward in the column and the vapors rising upward. As shown in FIG. 1, the fractionation tower may consist of two

sections. The upper absorbing (rectification) section 16a contains the trays and/or packing to provide the necessary contact between the vapors rising upward and cold liquid falling downward to condense and absorb the ethane and heavier components; the lower stripping (demethanizing) section 16b contains the trays and/or packing to provide the necessary contact between the liquids falling downward and the vapors rising upward. The demethanizing section also includes one or more reboilers (such as reboiler 22) which heat and vaporize a portion of the liquids flowing down the column to provide the stripping vapors which flow up the column. These vapors strip the methane from the liquids, so that the bottom liquid product (stream 47) is substantially devoid of methane and comprised of the majority of the C<sub>2</sub> components and heavier hydrocarbons contained in the LNG feed stream. (Because of the temperature level required in the column reboiler, a high level source of utility heat is typically required to provide the heat input to the reboiler, such as the heating medium used in this example.) The liquid product stream 47 exits the bottom of the tower at 71°F [22°C], based on a typical specification of a methane to ethane ratio of 0.005:1 on a volume basis in the bottom product. After cooling to 19°F [-7°C] in heat exchanger 13 as described previously, the liquid product (stream 47a) flows to storage or further processing.

[0017] The demethanizer overhead vapor, stream 46, is the methane-rich residue gas, leaving the column at -141°F [-96°C]. After being heated to -40°F [-40°C] in cross exchanger 29 so that conventional metallurgy may be used in compressor 28, stream 46a enters compressor 28 (driven by a supplemental power source) and is compressed to sales line pressure (stream 46b). Following cooling to 50°F [10°C] in cross exchanger 29, the

residue gas product (stream 46c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0018] The relative split of the LNG into streams 42 and 43 is typically adjusted to maintain the desired recovery level of the desired C<sub>2</sub> components and heavier hydrocarbon components in the bottom liquid product (stream 47). Increasing the split to stream 42 feeding the top of fractionation tower 16 will increase the recovery level, until a point is reached where the composition of demethanizer overhead vapor (stream 46) is in equilibrium with the composition of the LNG (i.e., the composition of the liquid in stream 42a). Once this point has been reached, further increasing the split to stream 42 will not raise the recovery any further, but will simply increase the amount of high level utility heat required in reboiler 22 because less of the LNG is split to stream 43 and heated with low level utility heat in heat exchanger 14. (High level utility heat is normally more expensive than low level utility heat, so lower operating cost is usually achieved when the use of low level heat is maximized and the use of high level heat is minimized.) For the process conditions shown in FIG. 1, the amount of LNG split to stream 42 has been set at just slightly less than this maximum amount, so that the prior art process can achieve its maximum recovery without unduly increasing the heat load in reboiler 22.

[0019] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 1 is set forth in the following table:

Table I

(FIG. 1)

## Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	4,286	440	145	49	4,941
43	5,238	537	177	60	6,038
46	9,513	54	4	0	9,618
47	11	923	318	109	1,361

Recoveries\*

Ethane	94.43%
Propane	99.03%
Butanes+	99.78%

Power

LNG Feed Pump	276 HP	[ 454 kW]
Residue Gas Compressor	5,267 HP	[ 8,659 kW]
Totals	5,543 HP	[ 9,113 kW]

Low Level Utility Heat

LNG Heater	34,900 MBTU/Hr	[ 22,546 kW]
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High Level Utility Heat

Demethanizer Reboiler	8,280 MBTU/Hr	[ 5,349 kW]
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\* (Based on un-rounded flow rates)

[0020] This prior art process can also be adapted to produce an LPG product containing the majority of the C<sub>3</sub> components and heavier hydrocarbon components present in the feed stream as shown in FIG. 2. The processing scheme for the FIG. 2 process is essentially the same as that used for the FIG. 1 process described previously. The only significant differences are that the heat input of reboiler 22 has been increased to strip the C<sub>2</sub> components from the liquid product (stream 47) and the operating pressure of fractionation tower 16 has been raised slightly.

[0021] The liquid product stream 47 exits the bottom of fractionation tower 16 (commonly referred to as a deethanizer when producing an LPG product) at 189°F [87°C], based on a typical specification of an ethane to propane ratio of 0.020:1 on a molar basis in the bottom product. After cooling to 125°F [52°C] in heat exchanger 13, the liquid product (stream 47a) flows to storage or further processing.

[0022] The deethanizer overhead vapor (stream 46) leaves the column at -90°F [-68°C], is heated to -40°F [-40°C] in cross exchanger 29 (stream 46a), and is compressed by compressor 28 to sales line pressure (stream 46b). Following cooling to 83°F [28°C] in cross exchanger 29, the residue gas product (stream 46c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0023] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 2 is set forth in the following table:

Table II

(FIG. 2)

## Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	4,286	440	145	49	4,941
43	5,238	537	177	60	6,038
46	9,524	971	14	1	10,557
47	0	6	308	108	422

Recoveries\*

Propane 95.78%

Butanes+ 99.09%

Power

LNG Feed Pump	298 HP	[ 490 kW]
Residue Gas Compressor	5,107 HP	[ 8,396 kW]
Totals	5,405 HP	[ 8,886 kW]

Low Level Utility Heat

LNG Heater 35,536 MBTU/Hr [ 22,956 kW]

High Level Utility Heat

Deethanizer Reboiler 16,525 MBTU/Hr [ 10,675 kW]

\* (Based on un-rounded flow rates)

[0024] If a slightly lower recovery level is acceptable, this prior art process can produce an LPG product using less power and high level utility heat as shown in FIG. 3. The processing scheme for the FIG. 3 process is essentially the same as that used for the FIG. 2 process described previously. The only significant difference is that the relative split between stream 42 and 43 has been adjusted to minimize the duty of reboiler 22 while providing the desired recovery of the C<sub>3</sub> components and heavier hydrocarbon components.

[0025] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 3 is set forth in the following table:

Table III

(FIG. 3)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	3,604	370	122	41	4,155
43	5,920	607	200	68	6,824
46	9,524	971	16	1	10,559
47	0	6	306	108	420

Recoveries\*

Propane	95.00%
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Butanes+	99.04%
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Power

LNG Feed Pump	302 HP	[ 496 kW]
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Residue Gas Compressor	5,034 HP	[ 8,276 kW]
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Totals	5,336 HP	[ 8,772 kW]
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Low Level Utility Heat

LNG Heater	40,247 MBTU/Hr	[ 26,000 kW]
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High Level Utility Heat

Deethanizer Reboiler	11,827 MBTU/Hr	[ 7,640 kW]
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\* (Based on un-rounded flow rates)

[0026] FIG. 4 shows an alternative prior art process in accordance with U.S. Pat. No. 2,952,984 that can achieve higher recovery levels than the prior art process used in FIG. 1. The process of FIG. 4, adapted here to produce an NGL product containing the majority of the C<sub>2</sub> components and heavier hydrocarbon components present in the feed stream, has been applied to the same LNG composition and conditions as described previously for FIG. 1.

[0027] In the simulation of the FIG. 4 process, the LNG to be processed (stream 41) from LNG tank 10 enters pump 11 at -255°F [-159°C]. Pump 11 elevates the pressure of the LNG sufficiently so that it can flow through heat exchangers and thence to fractionation tower 16. Stream 41a exiting the pump is heated first to -213°F [-136°C]

in reflux condenser 17 as it provides cooling to the overhead vapor (stream 46) from fractionation tower 16. The partially heated stream 41b is then heated to -200°F [-129°C] (stream 41c) in heat exchanger 13 by cooling the liquid product from the column (stream 47), and then further heated to -137°F [-94°C] (stream 41d) in heat exchanger 14 using low level utility heat. After expansion to the operating pressure (approximately 400 psia [2,758 kPa(a)]) of fractionation tower 16 by valve 15, stream 41e flows to a mid-column feed point at its bubble point, approximately -137°F [-94°C].

[0028] Overhead stream 46 leaves the upper section of fractionation tower 16 at -146°F [-99°C] and flows to reflux condenser 17 where it is cooled to -147°F [-99°C] and partially condensed by heat exchange with the cold LNG (stream 41a) as described previously. The partially condensed stream 46a enters reflux separator 18 wherein the condensed liquid (stream 49) is separated from the uncondensed vapor (stream 48). The liquid stream 49 from reflux separator 18 is pumped by reflux pump 19 to a pressure slightly above the operating pressure of demethanizer 16 and stream 49a is then supplied as cold top column feed (reflux) to demethanizer 16. This cold liquid reflux absorbs and condenses the C<sub>2</sub> components and heavier hydrocarbon components from the vapors rising in the upper rectification section of demethanizer 16.

[0029] The liquid product stream 47 exits the bottom of fractionation tower 16 at 71°F [22°C], based on a methane to ethane ratio of 0.005:1 on a volume basis in the bottom product. After cooling to 18°F [-8°C] in heat exchanger 13 as described previously, the liquid product (stream 47a) flows to storage or further processing. The residue gas (stream 48) leaves reflux separator 18 at -147°F [-99°C], is heated to -40°F

[-40°C] in cross exchanger 29 (stream 48a), and is compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to 43°F [6°C] in cross exchanger 29, the residue gas product (stream 48c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0030] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 4 is set forth in the following table:

Table IV

(FIG. 4)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
46	12,476	3	0	0	12,531
49	2,963	2	0	0	2,970
48	9,513	1	0	0	9,561
47	11	976	322	109	1,418

Recoveries\*

Ethane	99.90%
Propane	100.00%
Butanes+	100.00%

Power

LNG Feed Pump	287 HP	[ 472 kW]
Reflux Pump	9 HP	[ 15 kW]
Residue Gas Compressor	5,248 HP	[ 8,627 kW]
Totals	5,544 HP	[ 9,114 kW]

Low Level Utility Heat

LNG Heater	11,265 MBTU/Hr	[ 7,277 kW]
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High Level Utility Heat

Demethanizer Reboiler	30,968 MBTU/Hr	[ 20,005 kW]
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\* (Based on un-rounded flow rates)

[0031] Comparing the recovery levels displayed in Table IV above for the FIG. 4 prior art process with those in Table I for the FIG. 1 prior art process shows that the FIG. 4 process can achieve substantially higher ethane, propane, and butanes+ recoveries. However, comparing the utilities consumptions in Table IV with those in Table I shows that the high level utility heat required for the FIG. 4 process is much higher than that for the FIG. 1 process because the FIG. 4 process does not allow for optimum use of low level utility heat.

[0032] This prior art process can also be adapted to produce an LPG product containing the majority of the C<sub>3</sub> components and heavier hydrocarbon components present in the feed stream as shown in FIG. 5. The processing scheme for the FIG. 5 process is essentially the same as that used for the FIG. 4 process described previously. The only significant differences are that the heat input of reboiler 22 has been increased to strip the C<sub>2</sub> components from the liquid product (stream 47) and the operating pressure of fractionation tower 16 has been raised slightly. The LNG composition and conditions are the same as described previously for FIG. 2.

[0033] The liquid product stream 47 exits the bottom of deethanizer 16 at 190°F [88°C], based on an ethane to propane ratio of 0.020:1 on a molar basis in the bottom product. After cooling to 125°F [52°C] in heat exchanger 13, the liquid product (stream 47a) flows to storage or further processing. The residue gas (stream 48) leaves reflux separator 18 at -94°F [-70°C], is heated to -40°F [-40°C] in cross exchanger 29 (stream 48a), and is compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to 79°F [26°C] in cross exchanger 29, the residue gas product (stream 48c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0034] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 5 is set forth in the following table:

Table V

(FIG. 5)

## Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
46	11,401	2,783	3	0	14,238
49	1,877	1,812	3	0	3,696
48	9,524	971	0	0	10,542
47	0	6	322	109	437

Recoveries\*

Propane 99.90%

Butanes+ 100.00%

Power

LNG Feed Pump 309 HP [ 508 kW]

Reflux Pump 12 HP [ 20 kW]

Residue Gas Compressor 5,106 HP [ 8,394 kW]

Totals 5,427 HP [ 8,922 kW]

Low Level Utility Heat

LNG Heater 1,689 MBTU/Hr [ 1,091 kW]

High Level Utility Heat

Deethanizer Reboiler 49,883 MBTU/Hr [ 32,225 kW]

\* (Based on un-rounded flow rates)

[0035] If a slightly lower recovery level is acceptable, this prior art process can produce an LPG product using less power and high level utility heat as shown in FIG. 6. The processing scheme for the FIG. 6 process is essentially the same as that used for the FIG. 5 process described previously. The only significant difference is that the outlet temperature of stream 46a from reflux condenser 17 has been adjusted to minimize the duty of reboiler 22 while providing the desired recovery of the C<sub>3</sub> components and heavier hydrocarbon components. The LNG composition and conditions are the same as described previously for FIG. 3.

[0036] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 6 is set forth in the following table:

Table VI

(FIG. 6)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
46	10,485	1,910	97	0	12,541
49	961	939	81	0	1,983
48	9,524	971	16	0	10,558
47	0	6	306	109	421

Recoveries\*

Propane	95.00%
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Butanes+	100.00%
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Power

LNG Feed Pump	309 HP	[ 508 kW]
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Reflux Pump	7 HP	[ 12 kW]
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Residue Gas Compressor	5,108 HP	[ 8,397 kW]
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Totals	5,424 HP	[ 8,917 kW]
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Low Level Utility Heat

LNG Heater	8,230 MBTU/Hr	[ 5,317 kW]
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High Level Utility Heat

Deethanizer Reboiler	43,768 MBTU/Hr	[ 28,274 kW]
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\* (Based on un-rounded flow rates)

[0037] FIG. 7 shows another alternative prior art process in accordance with U.S. Pat. No. 5,114,451 that can also achieve higher recovery levels than the prior art process used in FIG. 1. The process of FIG. 7, adapted here to produce an NGL product containing the majority of the C<sub>2</sub> components and heavier hydrocarbon components present in the feed stream, has been applied to the same LNG composition and conditions as described previously for FIGS. 1 and 4.

[0038] In the simulation of the FIG. 7 process, the LNG to be processed (stream 41) from LNG tank 10 enters pump 11 at -255°F [-159°C]. Pump 11 elevates the pressure of the LNG sufficiently so that it can flow through heat exchangers and thence

to fractionation tower 16. Stream 41a exiting the pump is split into two portions, streams 42 and 43. The second portion, stream 43, is heated prior to entering fractionation tower 16 so that all or a portion of it is vaporized, reducing the amount of liquid flowing down fractionation tower 16 and allowing the use of a smaller diameter column. In the example shown in FIG. 7, stream 43 is first heated to -226°F [-143°C] in heat exchanger 13 by cooling the liquid product from the column (stream 47). The partially heated stream 43a is then further heated to 30°F [-1°C] (stream 43b) in heat exchanger 14 using low level utility heat. After expansion to the operating pressure (approximately 395 psia [2,723 kPa(a)]) of fractionation tower 16 by valve 15, stream 43c flows to a lower mid-column feed point at 27°F [-3°C].

[0039] The proportion of the total feed in stream 41a flowing to the column as stream 42 is controlled by valve 12, and is typically 50% or less of the total feed. Stream 42a flows from valve 12 to heat exchanger 17 where it is heated as it cools, substantially condenses, and subcools stream 49a. The heated stream 42b then flows to demethanizer 16 at an upper mid-column feed point at -160°F [-107°C].

[0040] Tower overhead stream 46 leaves demethanizer 16 at -147°F [-99°C] and is divided into two portions. The major portion, stream 48, is the methane-rich residue gas. It is heated to -40°F [-40°C] in cross exchanger 29 (stream 48a) and compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to 43°F [6°C] in cross exchanger 29, the residue gas product (stream 48c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0041] The minor portion of the tower overhead, stream **49**, enters compressor **26**, which supplies a modest boost in pressure to overcome the pressure drops in heat exchanger **17** and control valve **27**, as well as the static head due to the height of demethanizer **16**. The compressed stream **49a** is cooled to -247°F [-155°C] to substantially condense and subcool it (stream **49b**) by a portion of the LNG feed (stream **42a**) in heat exchanger **17** as described previously. Stream **49b** flows through valve **27** to lower its pressure to that of fractionation tower **16**, and resulting stream **49c** flows to the top feed point of demethanizer **16** to serve as reflux for the tower.

[0042] The liquid product stream **47** exits the bottom of fractionation tower **16** at 70°F [21°C], based on a methane to ethane ratio of 0.005:1 on a volume basis in the bottom product. After cooling to 18°F [-8°C] in heat exchanger **13** as described previously, the liquid product (stream **47a**) flows to storage or further processing.

[0043] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 7 is set forth in the following table:

Table VII

(FIG. 7)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	4,762	488	161	54	5,489
43	4,762	489	161	55	5,490
46	11,503	1	0	0	11,561
49	1,990	0	0	0	2,000
48	9,513	1	0	0	9,561
47	11	976	322	109	1,418

Recoveries\*

Ethane	99.88%
Propane	100.00%
Butanes+	100.00%

Power

LNG Feed Pump	276 HP	[ 454 kW]
Recycle Compressor	48 HP	[ 79 kW]
Residue Gas Compressor	5,249 HP	[ 8,629 kW]
Totals	5,573 HP	[ 9,162 kW]

Low Level Utility Heat

LNG Heater	31,489 MBTU/Hr	[ 20,342 kW]
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High Level Utility Heat

Demethanizer Reboiler	10,654 MBTU/Hr	[ 6,883 kW]
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\* (Based on un-rounded flow rates)

[0044] Comparing the recovery levels displayed in Table VII above for the FIG. 7 prior art process with those in Table I for the FIG. 1 prior art process shows that the FIG. 7 process can achieve substantially higher ethane, propane, and butanes+ recoveries, essentially the same as those achieved by the FIG. 4 prior art process as shown in Table IV. Further, comparing the utilities consumptions in Table VII with those in Table IV shows that the high level utility heat required for the FIG. 7 process is much lower than that for the FIG. 4. In fact, the high level utility heat required for the FIG. 7 process is only about 29% higher than the FIG. 1 process.

[0045] This prior art process can also be adapted to produce an LPG product containing the majority of the C<sub>3</sub> components and heavier hydrocarbon components present in the feed stream as shown in FIG. 8. The processing scheme for the FIG. 8 process is essentially the same as that used for the FIG. 7 process described previously. The only significant differences are that the heat input of reboiler 22 has been increased to strip the C<sub>2</sub> components from the liquid product (stream 47), the relative split between stream 42 and 43 has been adjusted to minimize the duty of reboiler 22 while providing the desired recovery of the C<sub>3</sub> components and heavier hydrocarbon components, and the operating pressure of fractionation tower 16 has been raised slightly. The LNG composition and conditions are the same as described previously for FIGS. 2 and 5.

[0046] The liquid product stream 47 exits the bottom of deethanizer 16 at 189°F [87°C], based on an ethane to propane ratio of 0.020:1 on a molar basis in the bottom product. After cooling to 124°F [51°C] in heat exchanger 13, the liquid product (stream 47a) flows to storage or further processing. The residue gas (stream 48) at -93°F [-70°C] is heated to -40°F [-40°C] in cross exchanger 29 (stream 48a) and compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to 78°F [25°C] in cross exchanger 29, the residue gas product (stream 48c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0047] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 8 is set forth in the following table:

Table VIII

(FIG. 8)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	5,714	586	193	65	6,587
43	3,810	391	129	44	4,392
46	12,676	1,292	0	0	14,032
49	3,152	321	0	0	3,490
48	9,524	971	0	0	10,542
47	0	6	322	109	437

Recoveries\*

Propane	99.90%
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Butanes+	100.00%
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Power

LNG Feed Pump	302 HP	[ 496 kW]
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Recycle Compressor	104 HP	[ 171 kW]
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Residue Gas Compressor	5,033 HP	[ 8,274 kW]
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Totals	5,439 HP	[ 8,941 kW]
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Low Level Utility Heat

LNG Heater	25,468 MBTU/Hr	[ 16,452 kW]
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High Level Utility Heat

Demethanizer Reboiler	25,808 MBTU/Hr	[ 16,672 kW]
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\* (Based on un-rounded flow rates)

[0048] If a slightly lower recovery level is acceptable, this prior art process can produce an LPG product using less power and high level utility heat as shown in FIG. 9. The processing scheme for the FIG. 9 process is essentially the same as that used for the FIG. 8 process described previously. The only significant differences are that the relative split between stream 42 and 43 and the flow rate of recycle stream 49 have been adjusted to minimize the duty of reboiler 22 while providing the desired recovery of the C<sub>3</sub> components and heavier hydrocarbon components. The LNG composition and conditions are the same as described previously for FIGS. 3 and 6.

[0049] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 9 is set forth in the following table:

Table IX

(FIG. 9)

## Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	4,374	449	148	50	5,042
43	5,150	528	174	59	5,937
46	11,327	1,155	19	0	12,558
49	1,803	184	3	0	2,000
48	9,524	971	16	0	10,558
47	0	6	306	109	421

Recoveries\*

Propane	95.00%
Butanes+	100.00%

Power

LNG Feed Pump	302 HP	[ 496 kW]
Recycle Compressor	61 HP	[ 100 kW]
Residue Gas Compressor	5,034 HP	[ 8,276 kW]
Totals	5,397 HP	[ 8,872 kW]

Low Level Utility Heat

LNG Heater	34,868 MBTU/Hr	[ 22,525 kW]
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High Level Utility Heat

Demethanizer Reboiler	16,939 MBTU/Hr	[ 10,943 kW]
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\* (Based on un-rounded flow rates)

DESCRIPTION OF THE INVENTION

Example 1

[0050] FIG. 10 illustrates a flow diagram of a process in accordance with the present invention. The LNG composition and conditions considered in the process presented in FIG. 10 are the same as those in FIGS. 1, 4, and 7. Accordingly, the FIG. 10 process can be compared with that of the FIGS. 1, 4, and 7 processes to illustrate the advantages of the present invention.

[0051] In the simulation of the FIG. 10 process, the LNG to be processed (stream 41) from LNG tank 10 enters pump 11 at -255°F [-159°C]. Pump 11 elevates the pressure of the LNG sufficiently so that it can flow through heat exchangers and thence to fractionation tower 16. Stream 41a exiting the pump is heated to -152°F [-102°C] in reflux condenser 17 as it provides cooling to the overhead vapor (stream 46) from fractionation tower 16. Stream 41b exiting reflux condenser 17 is split into two portions, streams 42 and 43. The first portion, stream 42, is expanded to the operating pressure (approximately 400 psia [2,758 kPa(a)]) of fractionation tower 16 by valve 12 and supplied to the tower at an upper mid-column feed point.

[0052] The second portion, stream 43, is heated prior to entering fractionation tower 16 so that all or a portion of it is vaporized, reducing the amount of liquid flowing down fractionation tower 16 and allowing the use of a smaller diameter column. In the example shown in FIG. 10, stream 43 is first heated to -137°F [-94°C] in heat exchanger 13 by cooling the liquid product from the column (stream 47). The partially heated stream 43a is then further heated to 30°F [-1°C] (stream 43b) in heat exchanger 14 using low level utility heat. After expansion to the operating pressure of fractionation tower 16 by valve 15, stream 43c flows to a lower mid-column feed point at 27°F [-3°C].

[0053] The demethanizer in fractionation tower 16 is a conventional distillation column containing a plurality of vertically spaced trays, one or more packed beds, or some combination of trays and packing. As shown in FIG. 10, the fractionation tower may consist of two sections. The upper absorbing (rectification) section 16a contains the trays and/or packing to provide the necessary contact between the vapors rising upward

and cold liquid falling downward to condense and absorb the ethane and heavier components; the lower stripping (demethanizing) section **16b** contains the trays and/or packing to provide the necessary contact between the liquids falling downward and the vapors rising upward. The demethanizing section also includes one or more reboilers (such as reboiler **22**) which heat and vaporize a portion of the liquids flowing down the column to provide the stripping vapors which flow up the column. The liquid product stream **47** exits the bottom of the tower at 71°F [22°C], based on a methane to ethane ratio of 0.005:1 on a volume basis in the bottom product. After cooling to 18°F [-8°C] in heat exchanger **13** as described previously, the liquid product (stream **47a**) flows to storage or further processing.

[0054] Overhead distillation stream **46** is withdrawn from the upper section of fractionation tower **16** at -146°F [-99°C] and flows to reflux condenser **17** where it is cooled to -147°F [-99°C] and partially condensed by heat exchange with the cold LNG (stream **41a**) as described previously. The partially condensed stream **46a** enters reflux separator **18** wherein the condensed liquid (stream **49**) is separated from the uncondensed vapor (stream **48**). The liquid stream **49** from reflux separator **18** is pumped by reflux pump **19** to a pressure slightly above the operating pressure of demethanizer **16** and stream **49a** is then supplied as cold top column feed (reflux) to demethanizer **16**. This cold liquid reflux absorbs and condenses the C<sub>2</sub> components and heavier hydrocarbon components from the vapors rising in the upper rectification section of demethanizer **16**.

[0055] The residue gas (stream **48**) leaves reflux separator **18** at -147°F [-99°C], is heated to -40°F [-40°C] in cross exchanger **29** (stream **48a**), and is compressed by

compressor **28** to sales line pressure (stream **48b**). Following cooling to 43°F [6°C] in cross exchanger **29**, the residue gas product (stream **48c**) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0056] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 10 is set forth in the following table:

Table X

(FIG. 10)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	3,048	313	103	35	3,513
43	6,476	664	219	74	7,466
46	17,648	8	0	0	17,717
49	8,135	7	0	0	8,156
48	9,513	1	0	0	9,561
47	11	976	322	109	1,418

Recoveries\*

Ethane	99.90%
Propane	100.00%
Butanes+	100.00%

Power

LNG Feed Pump	287 HP	[ 472 kW]
Reflux Pump	25 HP	[ 41 kW]
Residue Gas Compressor	5,248 HP	[ 8,628 kW]
Totals	5,560 HP	[ 9,141 kW]

Low Level Utility Heat

LNG Heater	32,493 MBTU/Hr	[ 20,991 kW]
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High Level Utility Heat

Demethanizer Reboiler	9,741 MBTU/Hr	[ 6,293 kW]
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\* (Based on un-rounded flow rates)

[0057] Comparing the recovery levels displayed in Table X above for the FIG. 10 process with those in Table I for the FIG. 1 prior art process shows that the present invention can achieve much higher liquids recovery efficiency than the FIG. 1 process. Comparing the utilities consumptions in Table X with those in Table I shows that the power requirement for the present invention is essentially the same as that for the FIG. 1 process, and that the high level utility heat required for the present invention is only slightly higher (about 18%) than that for the FIG. 1 process.

[0058] Comparing the recovery levels displayed in Table X with those in Tables IV and VII for the FIGS. 4 and 7 prior art processes shows that the present invention matches the liquids recovery efficiencies of the FIGS. 4 and 7 processes. Comparing the utilities consumptions in Table X with those in Tables IV and VII shows that the power requirement for the present invention is essentially the same as that for the FIGS. 4 and 7 processes, but that the high level utility heat required for the present invention is substantially lower (about 69% lower and 9% lower, respectively) than that for the FIGS. 4 and 7 processes.

[0059] There are three primary factors that account for the improved efficiency of the present invention. First, compared to the FIG. 1 prior art process, the present invention does not depend on the LNG feed itself to directly serve as the reflux for fractionation column 16. Rather, the refrigeration inherent in the cold LNG is used indirectly in reflux condenser 17 to generate a liquid reflux stream (stream 49) that contains very little of the C<sub>2</sub> components and heavier hydrocarbon components that are to be recovered, resulting in efficient rectification in the upper absorbing section 16a of fractionation tower 16 and avoiding the equilibrium limitations of the prior art FIG. 1 process (similar to the steps shown in the FIG. 4 prior art process). Second, compared to the FIG. 4 prior art process, splitting the LNG feed into two portions before feeding fractionation tower 16 allows more efficient use of low level utility heat, thereby reducing the amount of high level utility heat consumed by reboiler 22. The relatively colder portion of the LNG feed (stream 42a in FIG. 10) serves as a second reflux stream for fractionation tower 16, providing partial rectification of the vapors in the heated

portion (stream 43c in FIG. 10) so that heating and vaporizing this portion of the LNG feed does not unduly increase the load on reflux condenser 17. Third, compared to the FIG. 7 prior art process, using the entire LNG feed (stream 41a in FIG. 10) in reflux condenser 17 rather than just a portion (stream 42a in FIG. 7) allows generating more reflux for fractionation tower 16, as can be seen by comparing stream 49 in Table X with stream 49 in Table VII. The higher reflux flow allows more of the LNG feed to be heated using low level utility heat in heat exchanger 14 (compare stream 43 in Table X with stream 43 in Table VII), reducing the duty required in reboiler 22 and minimizing the amount of high level utility heat needed to meet the specification for the bottom liquid product from the demethanizer.

Example 2

[0060] The present invention can also be adapted to produce an LPG product containing the majority of the C<sub>3</sub> components and heavier hydrocarbon components present in the feed stream as shown in FIG. 11. The LNG composition and conditions considered in the process presented in FIG. 11 are the same as described previously for FIGS. 2, 5, and 8. Accordingly, the FIG. 11 process of the present invention can be compared to the prior art processes displayed in FIGS. 2, 5, and 8.

[0061] The processing scheme for the FIG. 11 process is essentially the same as that used for the FIG. 10 process described previously. The only significant differences are that the heat input of reboiler 22 has been increased to strip the C<sub>2</sub> components from the liquid product (stream 47) and the operating pressure of fractionation tower 16 has been raised slightly.

[0062] The liquid product stream 47 exits the bottom of deethanizer 16 at 189°F [87°C], based on an ethane to propane ratio of 0.020:1 on a molar basis in the bottom product. After cooling to 124°F [51°C] in heat exchanger 13, the liquid product (stream 47a) flows to storage or further processing. The residue gas (stream 48) leaves reflux separator 18 at -94°F [-70°C], is heated to -40°F [-40°C] in cross exchanger 29 (stream 48a), and is compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to 79°F [26°C] in cross exchanger 29, the residue gas product (stream 48c) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0063] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 11 is set forth in the following table:

Table XI  
(FIG. 11)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
42	3,048	313	103	35	3,513
43	6,476	664	219	74	7,466
46	12,067	3,425	4	0	15,547
49	2,543	2,454	4	0	5,005
48	9,524	971	0	0	10,542
47	0	6	322	109	437

Recoveries\*

Propane 99.90%

Butanes+ 100.00%

Power

LNG Feed Pump	309 HP	[ 508 kW]
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Reflux Pump	16 HP	[ 26 kW]
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Residue Gas Compressor	5,106 HP	[ 8,394 kW]
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Totals	5,431 HP	[ 8,928 kW]
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Low Level Utility Heat

LNG Heater	28,486 MBTU/Hr	[ 18,402 kW]
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High Level Utility Heat

Deethanizer Reboiler	23,077 MBTU/Hr	[ 14,908 kW]
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\* (Based on un-rounded flow rates)

[0064] Comparing the recovery levels displayed in Table XI above for the FIG. 11 process with those in Table II for the FIG. 2 prior art process shows that the present invention can achieve much higher liquids recovery efficiency than the FIG. 2 process. Comparing the utilities consumptions in Table XI with those in Table II shows that the power requirement for the present invention is essentially the same as that for the FIG. 2 process, although the high level utility heat required for the present invention is significantly higher (about 40%) than that for the FIG. 2 process.

[0065] Comparing the recovery levels displayed in Table XI with those in Tables V and VIII for the FIGS. 5 and 8 prior art processes shows that the present

invention matches the liquids recovery efficiencies of the FIGS. 5 and 8 processes. Comparing the utilities consumptions in Table XI with those in Tables V and VIII shows that the power requirement for the present invention is essentially the same as that for the FIGS. 5 and 8 processes, but that the high level utility heat required for the present invention is substantially lower (about 54% lower and 11% lower, respectively) than that for the FIGS. 5 and 8 processes.

### Example 3

[0066] If a slightly lower recovery level is acceptable, another embodiment of the present invention may be employed to produce an LPG product using much less power and high level utility heat. FIG. 12 illustrates such an alternative embodiment. The LNG composition and conditions considered in the process presented in FIG. 12 are the same as those in FIG. 11, as well as those described previously for FIGS. 3, 6, and 9. Accordingly, the FIG. 12 process of the present invention can be compared to the embodiment displayed in FIG. 11 and to the prior art processes displayed in FIGS. 3, 6, and 9.

[0067] In the simulation of the FIG. 12 process, the LNG to be processed (stream 41) from LNG tank 10 enters pump 11 at -255°F [-159°C]. Pump 11 elevates the pressure of the LNG sufficiently so that it can flow through heat exchangers and thence to absorber column 16. Stream 41a exiting the pump is heated first to -91°F [-69°C] in reflux condenser 17 as it provides cooling to the overhead vapor (distillation stream 46) withdrawn from contacting device absorber column 16. The partially heated stream 41b is then heated to -88°F [-67°C] (stream 41c) in heat exchanger 13 by cooling the liquid

product (stream 47) from fractionation stripper column 21, and then further heated to 30°F [-1°C] (stream 41d) in heat exchanger 14 using low level utility heat. After expansion to the operating pressure (approximately 855 psia [5,895 kPa(a)]) of absorber column 16 by valve 15, stream 41e flows to a lower column feed point on the column at 28°F [-2°C]. The liquid portion (if any) of expanded stream 41e commingles with liquids falling downward from the upper section of absorber column 16 and the combined liquid stream 44 exits the bottom of contacting device absorber column 16 at 17°F [-8°C]. The vapor portion of expanded stream 41e rises upward through absorber column 16 and is contacted with cold liquid falling downward to condense and absorb the C<sub>3</sub> components and heavier hydrocarbon components.

[0068] The combined liquid stream 44 from the bottom of the absorber column 16 is flash expanded to slightly above the operating pressure (430 psia [2,965 kPa(a)]) of stripper column 21 by expansion valve 20, cooling stream 44 to -11°F [-24°C] (stream 44a) before it enters fractionation stripper column 21 at a top column feed point. In the stripper column 21, stream 44a is stripped of its methane and C<sub>2</sub> components by the vapors generated in reboiler 22 to meet the specification of an ethane to propane ratio of 0.020:1 on a molar basis. The resulting liquid product stream 47 exits the bottom of stripper column 21 at 191°F [88°C] and is cooled to 126°F [52°C] in heat exchanger 13 (stream 47a) before flowing to storage or further processing.

[0069] The overhead vapor (stream 45) from stripper column 21 exits the column at 52°F [11°C] and enters overhead compressor 23 (driven by a supplemental power source). Overhead compressor 23 elevates the pressure of stream 45a to slightly above

the operating pressure of absorber column 16 so that stream 45a can be supplied to absorber column 16 at a lower column feed point. Stream 45a enters absorber column 16 at 144°F [62°C], whereupon it rises upward through absorber column 16 and is contacted with cold liquid falling downward to condense and absorb the C<sub>3</sub> components and heavier hydrocarbon components.

[0070] Overhead distillation stream 46 is withdrawn from contacting device absorber column 16 at -63°F [-53°C] and flows to reflux condenser 17 where it is cooled to -78°F [-61°C] and partially condensed by heat exchange with the cold LNG (stream 41a) as described previously. The partially condensed stream 46a enters reflux separator 18 wherein the condensed liquid (stream 49) is separated from the uncondensed vapor 18 (stream 48). The liquid stream 49 from reflux separator 18 is pumped by reflux pump 19 to a pressure slightly above the operating pressure of absorber column 16 and stream 49a is then supplied as cold top column feed (reflux) to absorber column 16. This cold liquid reflux absorbs and condenses the C<sub>3</sub> components and heavier hydrocarbon components from the vapors rising in absorber column 16.

[0071] The residue gas (stream 48) leaves reflux separator 18 at -78°F [-61°C], is heated to -40°F [-40°C] in cross exchanger 29 (stream 48a), and is compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to -37°F [-38°C] in cross exchanger 29, stream 48c is heated to 30°F [-1°C] using low level utility heat in heat exchanger 30 and the residue gas product (stream 48d) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0072] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 12 is set forth in the following table:

Table XII

(FIG. 12)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
44	705	447	552	129	1,835
45	705	441	246	20	1,414
46	31,114	4,347	93	0	35,687
49	21,590	3,376	77	0	25,129
48	9,524	971	16	0	10,558
47	0	6	306	109	421

Recoveries\*

Propane	95.01%
Butanes+	99.98%

Power

LNG Feed Pump	616 HP	[ 1,013 kW]
Reflux Pump	117 HP	[ 192 kW]
Overhead Compressor	422 HP	[ 694 kW]
Residue Gas Compressor	1,424 HP	[ 2,341 kW]
Totals	<hr/> 2,579 HP	<hr/> [ 4,240 kW]

Low Level Utility Heat

LNG Heater	32,436 MBTU/Hr	[ 20,954 kW]
Residue Gas Heater	<hr/> 12,541 MBTU/Hr	<hr/> [ 8,101 kW]
Totals	<hr/> 44,977 MBTU/Hr	<hr/> [ 29,055 kW]

High Level Utility Heat

Deethanizer Reboiler	7,336 MBTU/Hr	[ 4,739 kW]
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\* (Based on un-rounded flow rates)

[0073] Comparing Table XII above for the FIG. 12 embodiment of the present invention with Table XI for the FIG. 11 embodiment of the present invention shows that there is a reduction in liquids recovery (from 99.90% propane recovery and 100.00% butanes+ recovery to 95.01% propane recovery and 99.98% butanes+ recovery) for the FIG. 12 embodiment. However, the power and heat requirements for the FIG. 12 embodiment are less than one-half of those for the FIG. 11 embodiment. The choice of

which embodiment to use for a particular application will generally be dictated by the monetary value of the heavier hydrocarbons in the LPG product versus their corresponding value as gaseous fuel in the residue gas product, and by the cost of power and high level utility heat.

[0074] Comparing the recovery levels displayed in Table XII with those in Tables III, VI, and IX for the FIGS. 3, 6, and 9 prior art processes shows that the present invention matches the liquids recovery efficiencies of the FIGS. 3, 6, and 9 processes. Comparing the utilities consumptions in Table XII with those in Tables III, VI, and IX shows that the power requirement for this embodiment of the present invention is significantly less (about 52% lower) than that for the FIGS. 3, 6, and 9 processes, as is the high level utility heat required (about 38%, 83%, and 57% lower, respectively, than that for the FIGS. 3, 6, and 9 processes).

[0075] Comparing this embodiment of the present invention to the prior art process displayed in FIGS. 3, 6, and 9, note that while the operating pressure of fractionation stripper column 21 is the same as that of fractionation tower 16 in the three prior art processes, the operating pressure of contacting device absorber column 16 is significantly higher, 855 psia [5,895 kPa(a)] versus 430 psia [2,965 kPa(a)].

Accordingly, the residue gas enters compressor 28 at a higher pressure in the FIG. 12 embodiment of the present invention and less compression horsepower is therefore needed to deliver the residue gas to pipeline pressure.

[0076] Since the prior art processes perform rectification and stripping in the same tower (i.e., absorbing section 16a and stripping section 16b contained in

fractionation tower 16 in FIG. 1), the two operations must of necessity be performed at essentially the same pressure in the prior art processes. The power consumption of the prior art processes could be reduced by raising the operating pressure of deethanizer 16. Unfortunately, this is not advisable in this instance because of the detrimental effect on distillation performance in deethanizer 16 that would result from the higher operating pressure. This effect is manifested by poor mass transfer in deethanizer 16 due to the phase behavior of its vapor and liquid streams. Of particular concern are the physical properties that affect the vapor-liquid separation efficiency, namely the liquid surface tension and the differential in the densities of the two phases. As a result, the operating pressure of deethanizer 16 should not be raised above the values shown in FIGS. 3, 6, and 9, so there is no means available to reduce the power consumption of compressor 28 using the prior art process.

[0077] With overhead compressor 23 supplying the motive force to cause the overhead from stripper column 21 (stream 45 in FIG. 12) to flow to absorber column 16, the operating pressures of the rectification operation (absorber column 16) and the stripping operation (stripper column 21) are no longer coupled together as they are in the prior art processes. Instead, the operating pressures of the two columns can be optimized independently. In the case of stripper column 21, the pressure can be selected to insure good distillation characteristics, while for absorber column 16 the pressure can be selected to optimize the liquids recovery level versus the residue gas compression power requirements.

[0078] The dramatic reduction in the duty of reboiler 22 for the FIG. 12 embodiment of the present invention is the result of two factors. First, as liquid stream 44 from the bottom of absorber column 16 is flash expanded to the operating pressure of stripper column 21, a significant portion of the methane and C<sub>2</sub> components in this stream is vaporized. These vapors return to absorber column 16 in stream 45a to serve as stripping vapors for the liquids flowing downward in the absorber column, so that there is less of the methane and C<sub>2</sub> components to be stripped from the liquids in stripper column 21. Second, overhead compressor 23 is in essence a heat pump serving as a side reboiler to absorber column 16, since the heat of compression is supplied directly to the bottom of absorber column 16. This further reduces the amount of methane and C<sub>2</sub> components contained in stream 44 that must be stripped from the liquids in stripper column 21.

Example 4

[0079] A slightly more complex design that maintains the same C<sub>3</sub> component recovery with lower power consumption can be achieved using another embodiment of the present invention as illustrated in the FIG. 13 process. The LNG composition and conditions considered in the process presented in FIG. 13 are the same as those in FIG. 12. Accordingly, the FIG. 13 embodiment can be compared to the embodiment displayed in FIG. 12.

[0080] In the simulation of the FIG. 13 process, the LNG to be processed (stream 41) from LNG tank 10 enters pump 11 at -255°F [-159°C]. Pump 11 elevates the pressure of the LNG sufficiently so that it can flow through heat exchangers and thence to absorber column 16. Stream 41a exiting the pump is heated first to -104°F [-76°C] in

reflux condenser 17 as it provides cooling to the overhead vapor (distillation stream 46) withdrawn from contacting device absorber column 16. The partially heated stream 41b is then heated to -88°F [-67°C] (stream 41c) in heat exchanger 13 by cooling the overhead stream (stream 45a) and the liquid product (stream 47) from fractionation stripper column 21, and then further heated to 30°F [-1°C] (stream 41d) in heat exchanger 14 using low level utility heat. After expansion to the operating pressure (approximately 855 psia [5,895 kPa(a)]) of absorber column 16 by valve 15, stream 41e flows to a lower column feed point on absorber column 16 at 28°F [-2°C]. The liquid portion (if any) of expanded stream 41e commingles with liquids falling downward from the upper section of absorber column 16 and the combined liquid stream 44 exits the bottom of absorber column 16 at 5°F [-15°C]. The vapor portion of expanded stream 41e rises upward through absorber column 16 and is contacted with cold liquid falling downward to condense and absorb the C<sub>3</sub> components and heavier hydrocarbon components.

[0081] The combined liquid stream 44 from the bottom of contacting device absorber column 16 is flash expanded to slightly above the operating pressure (430 psia [2,965 kPa(a)]) of stripper column 21 by expansion valve 20, cooling stream 44 to -24°F [-31°C] (stream 44a) before it enters fractionation stripper column 21 at a top column feed point. In the stripper column 21, stream 44a is stripped of its methane and C<sub>2</sub> components by the vapors generated in reboiler 22 to meet the specification of an ethane to propane ratio of 0.020:1 on a molar basis. The resulting liquid product stream 47 exits

the bottom of stripper column 21 at 191°F [88°C] and is cooled to 126°F [52°C] in heat exchanger 13 (stream 47a) before flowing to storage or further processing.

[0082] The overhead vapor (stream 45) from stripper column 21 exits the column at 43°F [6°C] and flows to cross exchanger 24 where it is cooled to -47°F [-44°C] and partially condensed. Partially condensed stream 45a is further cooled to -99°F [-73°C] in heat exchanger 13 as previously described, condensing the remainder of the stream. Condensed liquid stream 45b then enters overhead pump 25, which elevates the pressure of stream 45c to slightly above the operating pressure of absorber column 16. Stream 45c returns to cross exchanger 24 and is heated to 38°F [3°C] and partially vaporized as it provides cooling to stream 45. Partially vaporized stream 45d is then supplied to absorber column 16 at a lower column feed point, whereupon its vapor portion rises upward through absorber column 16 and is contacted with cold liquid falling downward to condense and absorb the C<sub>3</sub> components and heavier hydrocarbon components. The liquid portion of stream 45d commingles with liquids falling downward from the upper section of absorber column 16 and becomes part of combined liquid stream 44 leaving the bottom of absorber column 16.

[0083] Overhead distillation stream 46 is withdrawn from contacting device absorber column 16 at -64°F [-53°C] and flows to reflux condenser 17 where it is cooled to -78°F [-61°C] and partially condensed by heat exchange with the cold LNG (stream 41a) as described previously. The partially condensed stream 46a enters reflux separator 18 wherein the condensed liquid (stream 49) is separated from the uncondensed vapor (stream 48). The liquid stream 49 from reflux separator 18 is pumped by reflux pump 19

to a pressure slightly above the operating pressure of absorber column 16 and stream 49a is then supplied as cold top column feed (reflux) to absorber column 16. This cold liquid reflux absorbs and condenses the C<sub>3</sub> components and heavier hydrocarbon components from the vapors rising in absorber column 16.

[0084] The residue gas (stream 48) leaves reflux separator 18 at -78°F [-61°C], is heated to -40°F [-40°C] in cross exchanger 29 (stream 48a), and is compressed by compressor 28 to sales line pressure (stream 48b). Following cooling to -37°F [-38°C] in cross exchanger 29, stream 48c is heated to 30°F [-1°C] using low level utility heat in heat exchanger 30 and the residue gas product (stream 48d) flows to the sales gas pipeline at 1315 psia [9,067 kPa(a)] for subsequent distribution.

[0085] A summary of stream flow rates and energy consumption for the process illustrated in FIG. 13 is set forth in the following table:

Table XIII

(FIG. 13)

Stream Flow Summary - Lb. Moles/Hr [kg moles/Hr]

<u>Stream</u>	<u>Methane</u>	<u>Ethane</u>	<u>Propane</u>	<u>Butanes+</u>	<u>Total</u>
41	9,524	977	322	109	10,979
44	850	534	545	127	2,058
45	850	528	239	18	1,637
46	28,574	3,952	83	0	32,732
49	19,050	2,981	67	0	22,174
48	9,524	971	16	0	10,558
47	0	6	306	109	421

Recoveries\*

Propane	95.05%
Butanes+	99.98%

Power

LNG Feed Pump	616 HP	[ 1,013 kW]
Reflux Pump	103 HP	[ 169 kW]
Overhead Pump	74 HP	[ 122 kW]
Residue Gas Compressor	1,424 HP	[ 2,341 kW]
Totals	2,217 HP	[ 3,645 kW]

Low Level Utility Heat

LNG Heater	32,453 MBTU/Hr	[ 20,965 kW]
Residue Gas Heater	12,535 MBTU/Hr	[ 8,098 kW]
Totals	44,988 MBTU/Hr	[ 29,063 kW]

High Level Utility Heat

Deethanizer Reboiler	8,218 MBTU/Hr	[ 5,309 kW]
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\* (Based on un-rounded flow rates)

[0086] Comparing Table XIII above for the FIG. 13 embodiment of the present invention with Table XII for the FIG. 12 embodiment of the present invention shows that the liquids recovery is the same for the FIG. 13 embodiment. Since the FIG. 13 embodiment uses a pump (overhead pump 25 in FIG. 13) rather than a compressor (overhead compressor 23 in FIG. 12) to route the overhead vapor from fractionation stripper column 21 to contacting device absorber column 16, less power is required by

the FIG. 13 embodiment. However, since the resulting stream **45d** supplied to absorber column **16** is not fully vaporized, more liquid leaves absorber column **16** in bottoms stream **44** and must be stripped of its methane and C<sub>2</sub> components in stripper column **21**, increasing the load on reboiler **22** and increasing the amount of high level utility heat required by the FIG. 13 embodiment of the present invention compared to the FIG. 12 embodiment. The choice of which embodiment to use for a particular application will generally be dictated by the relative costs of power versus high level utility heat and the relative capital costs of pumps and heat exchangers versus compressors.

Other Embodiments

[0087] In the FIG. 13 embodiment of the present invention, the partially heated LNG leaving reflux condenser **17** (stream **41b**) supplies the final cooling to the overhead vapor (stream **45a**) from fractionation stripper column **21**. In some instances, there may not be sufficient cooling available in stream **41b** to totally condense the overhead vapor. In this circumstance, an alternative embodiment of the present invention such as that shown in FIG. 14 could be employed. Heated liquefied natural gas stream **41e** is directed into contacting device absorber column **16** wherein distillation stream **46** and liquid stream **44** are formed and separated. Liquid stream **44** is directed into fractionation stripper column **21** wherein the stream is separated into vapor stream **45** and liquid product stream **47**. Vapor stream **45** is cooled sufficiently to partially condense it in cross exchanger **24** and heat exchanger **13**. An overhead separator **26** can be used to separate the partially condensed overhead stream **45b** into its respective vapor fraction (stream **50**) and liquid fraction (stream **51**). Liquid stream **51** enters overhead pump **25** and is

pumped through cross exchanger 24 to heat it and partially vaporize it (stream 51b). Vapor stream 50 is compressed by overhead compressor 23 (with optional heating before and/or cooling after compression via heat exchangers 31 and/or 32) to raise its pressure so that it can be combined with the outlet from cross exchanger 24 to form combined stream 45c that is thereafter supplied to absorber column 16 at a lower column feed point. Alternatively, as shown by the dashed line, some or all of the compressed vapor (stream 50c) may be supplied separately to absorber column 16 at a second lower column feed point. Some applications may favor heating the vapor prior to compression (as shown by dashed heat exchanger 31) to allow less expensive metallurgy in compressor 23 or for other reasons. Cooling the outlet from overhead compressor 23 (stream 50b), such as in dashed heat exchanger 32, may also be favored under some circumstances.

[0088] Some circumstances may favor cooling the high pressure stream leaving overhead compressor 23, such as with dashed heat exchanger 24 in FIG. 15. It may also be desirable to heat the overhead vapor before it enters the compressor (to allow less expensive metallurgy in the compressor, for instance), such as with dashed cross exchanger 24 in FIG. 16. The choice of whether to heat the inlet to the overhead compressor and/or cool the outlet from the overhead compressor will depend on the composition of the LNG, the desired liquid recovery level, the operating pressures of absorber column 16 and stripper column 21 and the resulting process temperatures, and other factors.

[0089] Some circumstances may favor using a split feed configuration for the LNG feed (as disclosed previously in FIGS. 10 and 11) when using the two column

embodiments of the present invention. As shown in FIGS. 15 through 18, the partially heated LNG (stream **41b** in FIGS. 15 and 16 and stream **41c** in FIGS. 17 and 18) can be divided into two portions, streams **42** and **43**, with the first portion in stream **42** supplied to contacting device absorber column **16** at an upper mid-column feed point without any further heating. After further heating, the second portion in stream **43** can then be supplied to absorber column **16** at a lower mid-column feed point, so that the cold liquids present in the first portion can provide partial rectification of the vapors in the second portion. The choice of whether to use the split feed configuration for the two column embodiments of the present invention will generally depend on the composition of the LNG and the desired liquid recovery level.

[0090] In the FIG. 17 embodiment using a split feed configuration for the LNG feed, liquid stream **44** is directed into fractionation stripper column **21** wherein the stream is separated into vapor stream **45** and liquid product stream **47**. The vapor stream is cooled in cross exchanger **24** and heat exchanger **33** to substantial condensation. The substantially condensed stream **45b** is pumped to higher pressure by pump **25**, heated in cross exchanger **24** to vaporize at least a portion of it, and thereafter supplied as stream **45d** to contacting device absorber column **16** at a lower column feed point.

[0091] In the FIG. 18 embodiment using a split feed configuration for the LNG feed, vapor stream **45** is cooled in cross exchanger **24** and heat exchanger **33** sufficiently to partially condense it and is thereafter separated in overhead separator **26** into its respective vapor fraction (stream **50**) and liquid fraction (stream **51**). Liquid stream **51** enters overhead pump **25** and is pumped through cross exchanger **24** to heat it and

partially vaporize it (stream **51b**). Vapor stream **50** is compressed by overhead compressor **23** (with optional heating before and/or cooling after compression via heat exchangers **31** and/or **32**) to raise its pressure so that it can be combined with the outlet from cross exchanger **24** to form combined stream **45c** that is thereafter supplied to absorber column **16** at a lower column feed point. Alternatively, as shown by the dashed line, some or all of the compressed vapor (stream **50c**) may be supplied separately to absorber column **16** at a second lower column feed point. Some applications may favor heating the vapor prior to compression (as shown by dashed heat exchanger **31**) to allow less expensive metallurgy in overhead compressor **23** or for other reasons. Cooling the outlet from overhead compressor **23** (stream **50b**), such as in dashed heat exchanger **32**, may also be favored under some circumstances.

[0092] Reflux condenser **17** may be located inside the tower above the rectification section of fractionation tower **16** or absorber column **16** as shown in FIG. 19. This eliminates the need for reflux separator **18** and reflux pump **19** shown in FIGS. 10 through 18 because the distillation stream is then both cooled and separated in the tower above the fractionation stages of the column. Alternatively, use of a dephlegmator (such as dephlegmator **27** in FIG. 20) in place of reflux condenser **17** in FIGS. 10 through 18 eliminates the need for reflux separator **18** and reflux pump **19** and also provides concurrent fractionation stages to supplement those in the upper section of the column. If the dephlegmator is positioned in a plant at grade level, it can be connected to a vapor/liquid separator and the liquid collected in the separator pumped to the top of the distillation column (either fractionation tower **16** or contacting device absorber column

16). The decision as to whether to include the reflux condenser inside the column or to use a dephlegmator usually depends on plant size and heat exchanger surface requirements.

[0093] It also should be noted that valves 12 and/or 15 could be replaced with expansion engines (turboexpanders) whereby work could be extracted from the pressure reduction of stream 42 in FIGS. 10, 11, and 15 through 18, stream 43b in FIGS. 10, 11, and 15 through 18, and/or stream 41d in FIGS. 12 through 14. In this case, the LNG (stream 41) must be pumped to a higher pressure so that work extraction is feasible. This work could be used to provide power for pumping the LNG stream, for compression of the residue gas or the stripper column overhead vapor, or to generate electricity. The choice between use of valves or expansion engines will depend on the particular circumstances of each LNG processing project.

[0094] In FIGS. 10-20, individual heat exchangers have been shown for most services. However, it is possible to combine two or more heat exchange services into a common heat exchanger, such as combining heat exchangers 13, 14, and 24 in FIG. 14 into a common heat exchanger. In some cases, circumstances may favor splitting a heat exchange service into multiple exchangers. The decision as to whether to combine heat exchange services or to use more than one heat exchanger for the indicated service will depend on a number of factors including, but not limited to, LNG flow rate, heat exchanger size, stream temperatures, etc.

[0095] It will be recognized that the relative amount of feed found in each branch of the split LNG feed to fractionation tower 16 or absorber column 16 will depend on

several factors, including LNG composition, the amount of heat which can economically be extracted from the feed, residue gas delivery pressure, and the quantity of horsepower available. More feed to the top of the column may increase recovery while increasing the duty in reboiler 22 and thereby increasing the high level utility heat requirements.

Increasing feed lower in the column reduces the high level utility heat consumption but may also reduce product recovery. The relative locations of the mid-column feeds may vary depending on LNG composition or other factors such as the desired recovery level and the amount of vapor formed during heating of the feed streams. Moreover, two or more of the feed streams, or portions thereof, may be combined depending on the relative temperatures and quantities of individual streams, and the combined stream then fed to a mid-column feed position.

[0096] While there have been described what are believed to be preferred embodiments of the invention, those skilled in the art will recognize that other and further modifications may be made thereto, e.g. to adapt the invention to various conditions, types of feed, or other requirements without departing from the spirit of the present invention as defined by the following claims.